CANADA SOUTHERN PETROLEUM, LTD.

1996 Annual Report
(Includes Report on Form 10-K)

CANADA SOUTHERN PETROLEUM LTD.

TO OUR SHAREHOLDERS:

Because of your continued support, our rights offering of 1.3 million shares last year was oversubscribed and $9 million was raised to continue the Kotaneelee gas field litigation and increase the Company's exploration and development activities.

The Kotaneelee field continues to perform well and produced 15.2 billion cubic feet of gas from two wells during 1996. The field is currently producing approximately 40-45 million cubic feet of gas per day. The Company expects to receive income from Kotaneelee in 1999, based upon current production and a price of $1.34 per mcf (the average 1996 price) and assuming the payout period is not changed as a result of the litigation. The payout period may change depending on gas prices and the amount of gas sold in 1997 and 1998.

The Company sustained a net loss of $1,461,000 or $.11 a share, for the year 1996, as compared to a loss of $1,162,000 or $.09 a share for the prior year. The expenses associated with the Kotaneelee litigation continue to adversely affect the results of operations of the Company. Legal expenses were approximately $1,610,000 during the year and exceeded this year's loss.

Last month, Mr. C. Dean Reasoner retired as a director for health related reasons. The Board of Directors wishes to recognize his many years of service and acknowledge his numerous contributions to the success of the Company.

On the adjoining page, there is a more detailed review of 1996 operations and a discussion of 1997 exploration plans.

We want to thank all of our shareholders for their continued support. The Company will continue to pursue its interest in the Kotaneelee gas field and at the same time increase its exploration and development activities in an effort to maximize shareholder value.

Respectfully submitted,

Charles J. Horne
President

Calgary, Alberta
April 1, 1997

REVIEW OF OPERATIONS

The Company's exploration and development activities in 1996 became very active with the drilling of 12 wells which resulted in 10 productive wells and 2 dry holes.

The successful rights offering in June 1996 allowed the Company to participate fully in the exploration and development drilling that occurred on its properties and will enable the Company to continue its participation in its ongoing exploration and development program.

Most of the activity in 1996 was concentrated in three areas of Alberta; Kitscoty, Atlee and Leduc, where a total of four horizontal oil wells, two vertical oil wells and one gas well were drilled. All of the wells are currently producing and two of the wells also had additional oil and gas zones which will be exploited by wells in 1997. There were also 3-D seismic programs carried out in all three areas, and combined with the drilling results outlined above, there is the potential for further exploration and development drilling. The results of the seismic program have not been fully evaluated at this time, but initial results indicate that as many as 12 wells could be drilled in 1997.

In British Columbia, the Company's main producing area, activity was less than expected because of lower gas prices early in the year, and then because of a shortage of drilling rigs later in the year. Although, the shortage of equipment continues to hamper the industry, four wells have been drilled on Company lands, and all are being completed as potential oil wells.

In Saskatchewan, there was one gas discovery, but it is currently shut-in pending further development of the field.

As well as the seismic and drilling activities described above, the Company continues to evaluate and acquire new leases. The largest transaction was the purchase of interests ranging from 10% to 45% in over 12,000 acres in Alberta which covers four different prospects. Two wells are planned for these lands, as soon as a rig is available. In addition, one prospect has been farmed out on a seismic option basis to a major oil company. A 3-D seismic survey of the leases has already been completed and the major oil company has until September 1, 1997 to decide whether to drill a well in order to earn an interest in the lease.

As stated previously, the Kotaneelee field continues to perform well, but unfortunately, further development and exploration drilling is unlikely until the current litigation is resolved. Data has now been received on new seismic completed on the field last year. This information is being integrated into previous studies to evaluate the Kotaneelee structure and, in particular, the west limits of the anticline, which still remains undrilled.

The Company is also examining prospects outside of Canada. Last year, the Company purchased a small interest in a U.S. project. The first two wells are currently shut-in as potential oil wells, a third well was dry and a fourth well is projected for the spring of 1997.

The Company expects another active year in 1997, in spite of the restraints imposed by industry wide equipment shortages and the Kotaneelee litigation.

FORM 10-K

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

(Mark One)

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED]**

For the fiscal year ended December 31, 1996

OR

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]**

For the transition period from ______________________ to ______________________

Commission file number 1-3793

CANADA SOUTHERN PETROLEUM LTD.

(Exact name of registrant as specified in its charter)

NOVA SCOTIA, CANADA	98-0085412
State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification No.)
Suite 1410, One Palliser Square 125 Ninth Avenue, S.E. Calgary, Alberta CANADA	T2G OP6
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (403) 269-7741

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Limited Voting Shares, $1 (Canadian) per share	Pacific Stock Exchange Boston Stock Exchange Toronto Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

(Title of Class)

NONE

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K §229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately U.S. $95,781,000 at March 18, 1997.

(APPLICABLE ONLY TO CORPORATE REGISTRANTS)

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Limited Voting Shares, par value $1.00 (Canadian) per share, 13,956, 540 shares outstanding as of March 18, 1997.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy Statement of Canada Southern Petroleum Ltd. related to the Annual Meeting of Shareholders for the year ended December 31, 1996, which is incorporated into Part III of this Form 10-K.

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Unless otherwise indicated, all dollar figures set forth are expressed in Canadian currency. The exchange rate at March 18, 1997 was $1.00 Canadian = U.S. $.7281.

PART I

Item 1. Business.

The nature of Canada Southern Petroleum Ltd.'s (the "Company" or "Canada Southern") business is described at Item 1(c) herein, and a description of its oil and gas properties in Canada appears in Item 2 herein. For additional information regarding the development of the Company's business, see "Properties" and "Supplemental Information on Oil and Gas Activities".

(a) General Development of Business

Yukon Territory - The Kotaneelee Field

The Company's principal asset is a 30% carried interest in the Kotaneelee gas field located on Ex-Permit 1007 (31,888 gross acres or 9,566 net acres) in the extreme southeastern corner of the Yukon Territory. This partially developed field is connected to a major pipeline system. Only three wells have been completed to date and are capable of an estimated output of in excess of 60 million cubic feet per day, the capacity of the field dehydration plant. Present production is approximately 40-45 million cubic feet ("mcf") per day. The operator is Anderson Exploration Ltd., which acquired all of Columbia Gas Development of Canada's interests. See "Legal Proceedings " for a discussion of the Kotaneelee Litigation concerning this asset.

Production at Kotaneelee commenced in February 1991. According to government reports, total production in billion cubic feet ("bcf") from the Kotaneelee gas field since 1991 has been as follows:

Calendar Year	Production (bcf)
1991	8.1
1992	18.0
1993	17.5
1994	16.7
1995	15.7
1996	15.2

In a 1989 application to the National Energy Board, a reserve study by the operator estimated total gas in place at 1.6 trillion cubic feet with proved and probable recoverable reserves of 781 BCF.

At present, the Company does not receive any cash payments from production but is credited with 30% of the gross revenues until a like percent of the working interest costs, exclusive of any interest expense, are recovered by the operator. The Company will not receive any payment from production revenues until its share of the working interest costs are recovered. When the deferred costs are recovered, 30% of gross revenues (net of gross overriding royalties) less 30% of current working interest costs will be paid to the Company. Gross overriding royalties amount to 10% to the Canadian Federal government and 4.06% to certain individuals. The operator has reported to the Company development costs totaling approximately $88,000,000 and, of that amount, approximately $21,800,000 remained to be recovered at December 31, 1996. The Company has contested the amount of costs that have been charged to the carried interest account. It is expected that the Company will begin to receive proceeds from the Kotaneelee gas field commencing in 1999, based upon a price of $1.34 per mcf (average 1996 price) and current production rates. The period before payment to the Company begins may be shorter or longer, depending on prevailing market conditions and the results of the Kotaneelee Litigation. Under ordinary circumstances, increased natural gas prices would result in a shorter period to payout.

British Columbia Properties

The Company's major source of income is from oil and gas fields in northeast British Columbia. These fields, developed in the 1950's and 1960's, produce revenue through both working and carried interest agreements. The major working interests in these fields are operated by Canadian Natural Resources Ltd. ("CNRL"). Petro Canada is the operator of the Company's carried interest lands in British Columbia.

In addition to the producing properties, since 1988 the Company has acquired a number of leases in northeast British Columbia by participating in British Columbia land sales. To date three wells have been drilled on the lands resulting in two oil discoveries and one dry hole. Currently, the Company is defining the prospects by geophysics. Work completed to date indicates that seven of the prospects justify drilling. The Company estimates that the drilling costs (excluding completion costs) of the seven prospects would be $1,625,000. However, as most of these wells would be wildcat wells (exploratory wells), the Company plans to reduce its risk by selling or farming out part of its interest. The timing of the drilling is dependent on the availability of funds and the Company anticipates that its average net cost per well (assuming a farmout or sale) would be approximately $75,000, or a total of $525,000, for drilling and completion costs.

On the working interest lands, the most successful of these wells was in the West Peejay field in British Columbia (Company interest 27.75%). This field has been produced for many years, without any attempt to explore the field's limits. The 1993 sale of the field by the majority owner and the appointment of a new operator resulted in three new producing oil wells in 1994. The operator has applied to unitize and waterflood the West Peejay field. Preliminary approval has been received and work is underway with one well drilled and a seismic program completed. The first well encountered oil and gas and it is expected that at least three more wells will be drilled in 1997. Once unitization is completed, the Company will have a 14.0152% working interest in the oil and 14.1113% working interest in the gas in the whole field rather than a 27.75% working interest in a part of the field.

CNRL operates the lands which also include the Company's working interest in the Peejay and Weasel fields. As of December 31, 1996, the Company held approximately 18,732 gross acres (4,434 net acres) in this area. The Company owns interest in the following units:

	Unit Acreage	Company %
Peejay Unit #1	4,529	3.1643
Weasel Unit #2	1,569	10.1775
Peejay Unit #3	5,923	15.4136

The Company also holds interests in 10 oil wells (2.64 net wells) and 10 gas wells. (2.28 net wells) not included in the above units. The Company estimates that the capital costs for its interests in the West Peejay field will aggregate approximately $750,000 for 1997.

The Company has a 33 1/3% working interest in the Paradise area. Two oil discoveries in the area remain shut-in because at current oil prices their production rates are uneconomic. The wells also encountered potential gas zones which have not been tested. A portion of the lands have been farmed out on a seismic option basis and the farmee has committed to drill a well on the lands, as soon as a surface lease and rig have been acquired. The Company will retain an overriding royalty before payout and a 6.67% working interest in the well after payout.

There has been further drilling and development work on the Company's carried interest properties at Buick Creek and Siphon. Initial production from this work shows promise with a rate of 3.8 million cubic feet per day from a horizontal well at Buick Creek. Capital costs charged to the carried interest account in 1996 were $375,000. During 1996, the Siphon area properties were sold by the operator and a new operator appointed. The Wargen area is also expected to change operators in 1997. The new owners of these fields are expected to aggressively exploit the properties with increased capital expenditures.

Carried interest lands are also held by the Company in the Ekwan, Clarke Lake, Siphon and Wargen fields. The Company retains a 21.25 % carried interest with a right to convert to a 21.25 % working interest in most of these fields. Interests in some of these wells are less than 21.25 % because of pooling or side agreements. As of December 31, 1996, there were 36 gas wells in these fields which are producing wells or wells considered to be capable of production.

Arctic Islands

As of December 31, 1996, the Company held working interests in 45,100 gross acres (1,817 net acres) and carried interests in 133,260 gross acres (37,255 net acres) in the Sverdrup Basin, located in the Arctic Islands. The Hecla, Whitefish, Drake Point, Roche Point, Kristoffer, Romulus and Bent Horn fields have been designated significant discovery lands ("SDL") by the Federal Government. The Company's interests in the SDL's have been retained pending development.

Marketing of Bent Horn Production

Panarctic Oils Ltd. ("Panarctic"), the operator, received Federal government regulatory approvals for a pilot project to move shipments of crude oil from the Bent Horn field by tanker through the Northwest Passage to southern Canada in 1985. Through December 31, 1996, approximately 2.7 million barrels of Bent Horn crude had been sold with deliveries being made at northern Canadian and European markets as well as the eastern seaboard market. In 1996, the operator decided to shut down production from the field and dismantle the production facilities because of economic uncertainties. The Company has a 5% carried interest in the area which has not yet reached payout status. The timing of payout is uncertain.

Northwest Territories Properties

The Company has a 45% carried interest in the Northwest Territories in the Celibeta field designated as Significant Discovery Lands ("SDL") by the Federal Government (1,594 gross acres and 717 net acres). The field is presently a shut-in gas field.

Alberta

The Company participated in 9 wells on the Alberta lands in 1996 which resulted in 6 oil wells, 1 gas well and 2 dry holes.

In 1994, the Company purchased a 5% working interest in the Kitscoty heavy oil field and the related facilities. Oil recovery from this field is being enhanced by steam injection. Two horizontal holes were drilled for production with the steam being injected through vertical holes. Production has increased from 60 bpd to 300 bpd.

In 1996, the Company purchased an additional 5% working interest in the Kitscoty field. Three more wells were drilled in 1996, two horizontal wells and one vertical well. All the wells encountered oil and are now on production. One well also discovered three potential gas zones which will be evaluated for future use as fuel for the steam generation needed to enhance the oil production.

The other successful wells in Alberta were at Atlee and Leduc. At Atlee, two horizontal wells were drilled and placed on production at a combined rate of 500 bpd. The operator plans to complete a 3D seismic program with the possibility of drilling six additional wells in 1997. The Company has a 12.5% working interest in the two producing wells.

At Leduc, three wells were drilled of which two were completed as oil and gas wells and one well was a dry hole. One well encountered two potential producing zones and is currently producing at the allowable rate of 68 bpd. The second zone containing oil and gas will be produced from a follow-up well to be drilled in early 1997. The other successful well was completed as a gas well and is producing 1.5 million cubic feet per day. The Company has a 15% working interest in these wells. The operator has indicated that is expects that at least two wells will be drilled on the Leduc properties in 1997, once the results of the 1996 3D seismic program have been evaluated.

The Company also acquired a 10-20% working interest in over 12,000 acres in four other areas of Alberta. These lands were purchased on the basis of seismic work which showed a number of promising prospects. Subsequently, additional seismic work has confirmed the potential of those prospects. One well will be drilled as soon as a rig is available and at least two additional wells are planned for 1997.

The Company's gas well at Drumheller remains shut-in and the Company has agreed to sell its interest in the Sylvan Lake well.

The Company has working interests ranging from 10% to 45% in a total of 40,702 gross (11,178 net) acres.

Saskatchewan

Under the Company's land acquisition program, it acquired a 3.75% working interest (2,560 gross acres - 96 net acres) in 4 sections in Saskatchewan in late 1994.

Two wells were drilled on these properties in early 1995, and, although both were abandoned, indications are that the leases have good oil potential and further seismic work was completed in 1996. A well was drilled on the basis of the new seismic program and the well tested over three million cubic feet per day from a gas zone. The well is currently shut-in.

Australia

The Company has a .08% working interest in 115,596 gross (90 net) acres in the Amadeus Basin in the Northern Territory in Australia. Because of the limited potential of the only remaining property, the Dingo gas field, the interest was written down to a nominal value in 1992. The Dingo gas field is a shut-in gas field which is not connected to a gas pipeline. Initial discussions have been held with a potential gas purchaser for the sale of approximately 7.4 BCF of gas over 10 years with a possible contract for 20 years. Magellan Petroleum Australia Limited ("MPAL") is presently operator of this property. Benjamin W. Heath and C. Dean Reasoner, directors of the Company, are also directors of MPAL. Mr. Reasoner resigned as a director of the Company on March 11, 1997.

United States

The Company has agreed to participate in the drilling of five wells in Texas. The first two wells drilled in 1996 resulted in oil discoveries, however, the wells are currently shut-in awaiting remedial work. Two more wells will be drilled by mid 1997.

(b) <u>Financial Information about Industry Segments</u>.

Since the Company is primarily engaged in only one industry, oil and gas exploration and development, this item is not applicable to the Company. See Item 8 for general financial information concerning the Company.

(c) (1) <u>Narrative Description of the Business</u>.

The Company was incorporated in 1954 under the Canada Corporations Act. In 1979, it became subject to the Canadian Business Corporations Act and in 1980, was continued under the Nova Scotia Companies Act.

The Company is, either in its own right, or through other entities, engaged in the exploration for and development of properties containing or believed to contain recoverable oil and gas reserves and the sale of oil and gas from these properties. Although many of the properties in which the Company has interests are undeveloped, all properties with proved reserves are partially or fully developed. The Company's interests in exploratory ventures are on properties located in Alberta, British Columbia, the Northwest and Yukon Territories and the Arctic Islands in Canada, and the Northern Territory of Australia. A principal asset of the Company is its 30% carried interest in the Kotaneelee field, a partially developed gas field (See Item 3 - "Legal Proceedings".) The Company also has interests in producing properties in British Columbia and Alberta.

Most of this acreage is covered by carried interest agreements, which provide that revenues are not payable to the Company until expenditures by the carrying partners have been recouped from production, and that operating decisions are made by the carrying partners. Generally, the Company may, at any time, as to each block or economic unit, elect to convert from a carried interest position to a working interest position by paying its share of the unrecouped expenditures for the unit, i.e., expenditures not recouped from production revenues. At December 31, 1996, the Company's share of unrecouped expenditures were as follows:

British Columbia:	
Ex-permit 149	$3,216,000
Yukon and Northwest Territories:	
Ex-permit 1007 (Kotaneelee)*	6,534,000
Ex-permit 2713 (Celibeta)	321,000

**See Item 3 - Legal Proceedings*

(i) Principal Products.

The majority of the Company's interests are carried interests. The Company also participates in the production and sale of crude oil, natural gas and natural gas liquids derived from its working interests.

(ii) Status of Product or Segment.

At present, some of the properties in which the Company has interests are undeveloped and/or nonproducing.

(iii) Raw Materials.

Not applicable.

(iv) Patents, Licenses, Franchises and Concessions Held.

Permits and concessions are important to the Company's operations, since they allow the search for and extraction of any oil, gas and minerals discovered on the areas covered. See the detailed schedule of properties under Item 2, "Properties."

(v) Seasonality of Business.

The Company's business is not seasonal, except that sales of natural gas peak during the winter heating season. Exploration and development activities are restricted in certain areas on a seasonal basis because extreme weather conditions affect transportation and the ability to pursue these activities.

(vi) Working Capital Items.

Not applicable.

(vii) Customers.

Substantially all oil production from the Company's properties for the current year was purchased by CNRL, the operator of the majority of the producing properties. Most of the natural gas produced from Company properties was sold by the operator, Petro Canada, to a company owned by certain British Columbia gas producers, Can West Gas Supply Inc. The production from the Kotaneelee gas field is also being sold to CanWest Gas Supply, Inc.

(viii) Backlog.

Not applicable.

(ix) Renegotiation of Profits or Termination of Contracts or Subcontracts at the Election of the Government.

Not applicable.

(x) Competitive Conditions in the Business.

The exploration for and production of oil and gas are highly competitive operations, both internally within the oil and gas industry and externally with producers of other types of energy. The ability to exploit a discovery of oil or gas is dependent upon considerations such as the ability to finance development costs, the availability of equipment, and engineering and construction delays and difficulties. The Company must compete with companies which have substantially greater resources available to them. Because the majority of Company interests are in remote areas, operation of its properties is more difficult and costly than in more accessible areas.

Furthermore, competitive conditions may be substantially affected by various forms of energy legislation which may have been or may be proposed in the United States and Canada; however, it is not possible to predict the nature of any such legislation which may ultimately be adopted or its effects upon the future operations of the Company. For a further discussion of Canadian governmental regulation of the petroleum industry, see Item 1(d)(2).

(xi) Research and Development.

Not applicable.

(xii) Environmental Regulation.

In the exploration for and development of natural resources, the Company is required to comply with significant environmental laws and regulations which add to the expense of those activities. The Company has not been required to spend significant sums to comply with clean up laws and regulations. Compliance by the Company with governmental provisions regulating the discharge of materials to the environment or otherwise relating to the protection of the environment are not expected to have a material effect on the capital expenditures, earnings or competitive position of the Company.

(xiii) Number of Persons Employed by Company.

The Company currently has three full time employees, all of whom are located in Canada. The Company also relies to a great extent on consultants for technical, legal, accounting and administrative services. The Company uses consultants because it is more cost effective than employing a larger full time staff.

(d) Financial Information about Foreign and Domestic Operations and Export Sales.

(1) Identifiable Assets.

Substantially all of the Company's operating assets are in Canada.

All of the Company's revenues are attributable to its operations in Canada.

(2) Risks Attendant to Foreign Operations.

The properties in which the Company has interests are located in Canada and are subject to certain risks involved in the ownership and development of such foreign property interests. These risks include but are not limited to those of: nationalization; expropriation; confiscatory taxation; native rights; changes in foreign

exchange controls; currency revaluation; burdensome royalty terms; export sales restrictions; limitations on the transfer of interests in exploration licenses; and other laws and regulations which may adversely affect the Company's properties, such as those providing for conversion, proration, curtailment, cessation or other forms of limiting or controlling production of, or exploration for, hydrocarbons. Thus, an investment in the Company represents an exposure to risks in addition to those inherent in petroleum exploratory ventures.

Governmental Regulation of the Canadian Oil and Natural Gas Industry

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government relating to land tenure, production, production facilities, pricing and marketing, royalties, environmental protection and other matters. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and natural gas industry in Canada. All current legislation is a matter of public record and the Company is unable to predict whether any additional legislation or amendments may be enacted.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms from two years and on terms and conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated. The term of both Crown and freehold leases will generally continue as long as oil or natural gas is produced from the property.

Oil and natural gas rights on federal lands outside of the provinces is generally regulated by the Government of Canada unless authority has been delegated by agreement to the territorial government or the government of the province adjacent to the federal offshore area. In May 1993, the Canada Yukon Oil and Gas Accord was signed which allows for the transfer to the Yukon of authority to administer and control oil and natural gas resources within that territory and for the establishment of an Oil and Gas Management Regime. The National Energy Board ("NEB") is working with Yukon officials to facilitate the transfer of oil and natural gas regulatory responsibilities in accordance with the Yukon Accord Implementation Agreement.

Production and Production Facilities

The Governments of Canada, Alberta, British Columbia and Saskatchewan have enacted statutory provisions regulating the production of oil and natural gas. These regulations may restrict the maximum allowable production from a well based on reservoir engineering and/or conservation practices. The construction and operation of facilities to recover and process oil and natural gas are also subject to regulation.

Pricing and Marketing - Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Certain purchasers periodically advertise for volumes of oil they are prepared to purchase and the price being offered for such volumes. The price depends in part on oil quality, prices of competing fuels, distance to market and the value of refined products. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council.

Pricing and Marketing - Natural Gas

In Canada, the price of natural gas is determined by negotiation between buyers and sellers, with the result that the market determines the price of natural gas. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. As is the case with oil, natural gas exports for a term of less than two years must be made pursuant to an NEB order, or, in the case of exports for a longer duration, pursuant to an NEB license and Governor in Council approval.

The Governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Royalties and Incentives

The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands may also be subject to provincial taxes and regulations. Crown royalties are determined by government regulation and are generally calculated as

a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the product produced. The value of the gross production for royalty purposes may be based on a deemed value for the product rather than the actual value received by the interest holder.

From time to time the Governments of Canada, Alberta, British Columbia and Saskatchewan have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging natural gas and oil exploration or enhanced recovery projects. Incentives are intended to enhance the existing cash flow of the oil and natural gas industry and to improve the economics of finding and developing new and more costly oil and natural gas reserves. Oil royalty holidays for specific wells and royalty reductions reduce the amount of Crown royalties paid by the interest holder to the respective government. Tax credit programs provide a rebate on Crown royalties paid.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on spills, releases or emissions of various substances produced in association with certain oil and natural gas industry operations. An environmental assessment and review may be required prior to initiating exploration or development projects or undertaking significant changes to existing projects. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of the appropriate authorities. A breach of such legislation may result in the imposition of fines or penalties. Federal environmental regulations also apply to the use and transport of certain restricted and prohibited substances. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and believes that it is in material compliance with applicable environmental laws and regulations. The Company has not been required to spend significant sums to comply with clean up laws and regulations. Compliance by the Company with governmental provisions regulating the discharge of materials to the environment or otherwise relating to the protection of the environment are not expected to have a material effect on the capital expenditures, earnings or competitive position of the Company.

(3) Data which Are Not Indicative of Current or Future Operations

Not applicable.

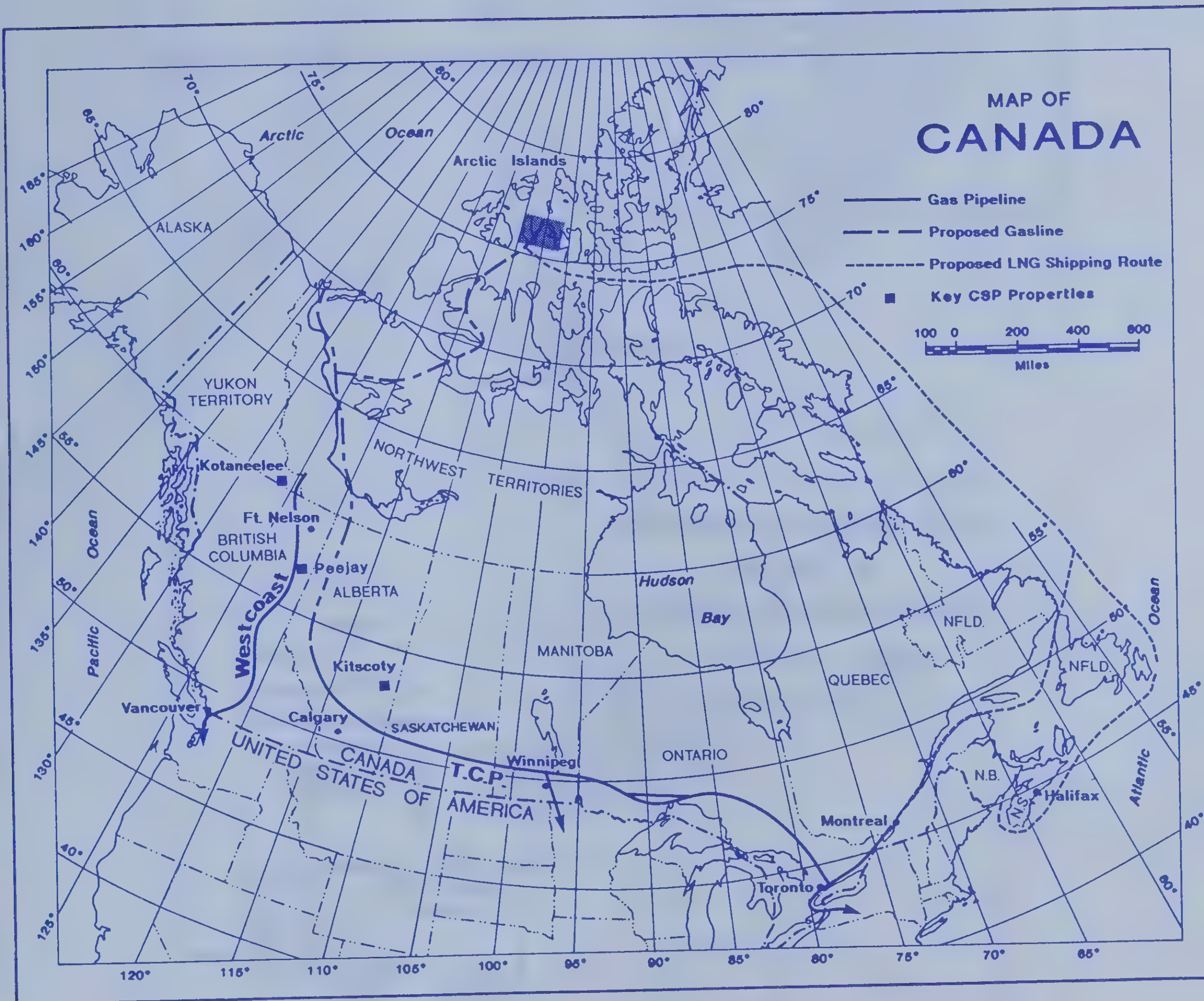
Item 2. Properties.

(a) The principal asset of the Company is its 30% carried interest in the Kotaneelee field, a partially developed gas field in the Yukon Territory. See Item 3. "Legal Proceedings." The Company also has interests in producing properties in British

Columbia and Alberta. Finally, the Company has interests in several exploration prospects. These interests are in exploratory ventures in properties located in Alberta, the Northwest Territories and the Arctic Islands in Canada, and the Northern Territory of Australia. Geophysical, geological and drilling work on the Company's properties is conducted by the operators under various agreements with the Company. The results of this work are reviewed by Company personnel and consultants retained by the Company.

The properties in Australia in which the Company has a minor interest are undeveloped and nonproducing, and the Company has not incurred significant costs in connection with these properties.

(b) (1) The information regarding reserves, costs of oil and gas activities, capitalized costs, discounted future net cash flows and results of operations is contained in Item 8. “Financial Statements and Supplementary Data.”


MAP OF
CANADA
Gas Pipeline
Proposed Gasline
Proposed LNG Shipping Route
Key CSP Properties
Miles
Arctic
Ocean
Arctic Islands
ALASKA
YUKON
TERRITORY
NORTHWEST TERRITORIES
Kotaneelee
Ft. Nelson
BRITISH
COLUMBIA
Peejay
ALBERTA
Westcoast
Kitscoty
Calgary
Vancouver
SASKATCHEWAN
MANITOBA
Hudson
Bay
ONTARIO
QUEBEC
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N.B.
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Halifax
Montreal
Toronto
Winnipeg
T.C.P.
CANADA
UNITED STATES OF AMERICA
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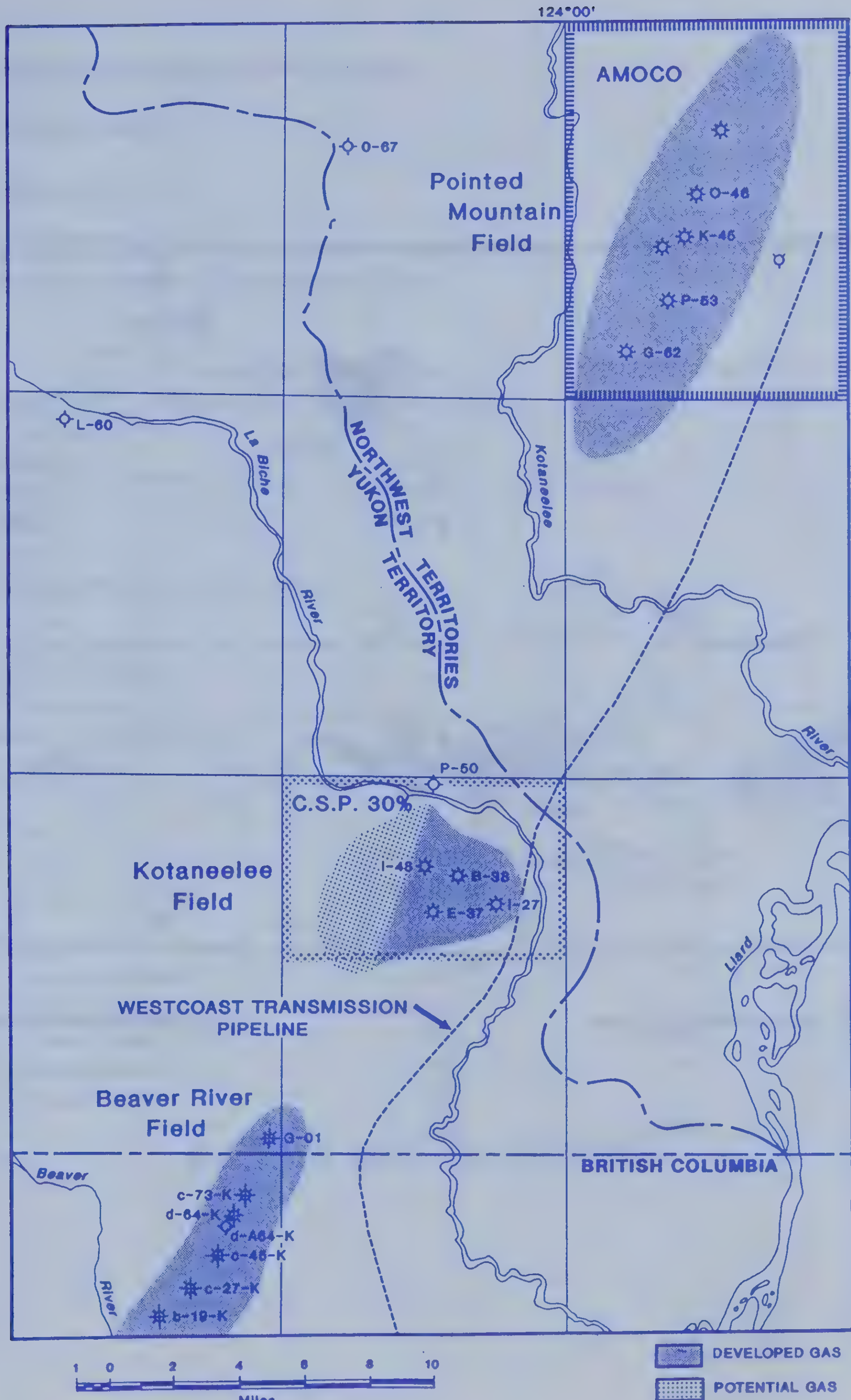
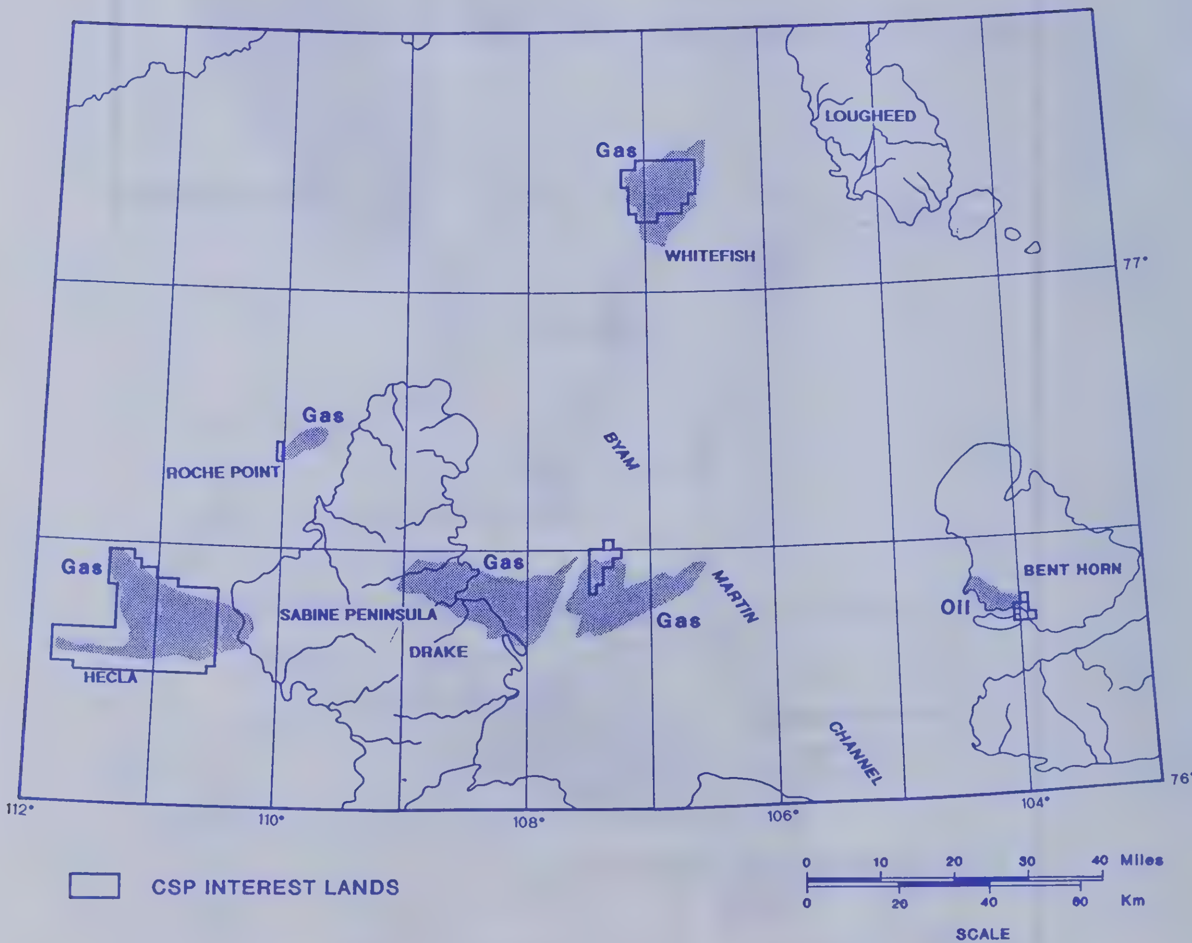
Atlantic
Ocean


N.E. British Columbia & Yukon, Northwest Territories
Canada Southern Interest Lands
MILES 10 0 10 20 30 40
KILOMETERS 10 0 10 20 30 40 50 60
POINTED MOUNTAIN
KOTANEELEE
YUKON
BEAVER RIVER
CELIBETA
NORTHWEST TERRITORIES
BRITISH COLUMBIA
ALBERTA
KOTCHO LAKE
FORT NELSON
FORT NELSON PROCESS PLANT
CLARKE LAKE
ADSETT
ELDER
EVERGREEN
WARGEN
N. BEATTON
MIKE
W. MILLIGAN
WEASEL
TOWN
HIGHWAY
BUICK CREEK
PEEJAY
OSPREY
INGA
STODDART
SIPHON
RED CREEK
FLATROCK
BOUNDARY LAKE
WILLISTON LAKE
TAYLOR PROCESS PLANT
DOE
DAWSON CREEK
CHETWYND
PINE RIVER PROCESS PLANT
BRITISH COLUMBIA
ALBERTA



KOTANEELEE FIELD



ARCTIC ISLAND FIELDS

(2) Reserves Reported to Other Agencies.

Not applicable.

(3) Production

Average sales price per unit and average production cost for oil and gas produced during the periods shown below are as follows:

Year	Average Sales Price Oil (per bbl.) ($)	Average Sales Price Gas (per mcf.) ($)	Average Production Costs Oil (per bbl.) ($)	Average Production Costs Gas (per mcf.) ($)
1996	25.47	1.64	8.67	.79
1995	22.39	1.30	10.08	.77
1994	19.14	1.84	7.49	.98

(4) Productive Wells and Acreage

Productive wells and acreage on working and carried interest properties as of December 31, 1996:

Gross Wells Oil	Gross Wells Gas	Net Wells Oil	Net Wells Gas
71	83	11.69	14.91

	Gross and Net Developed Acres Gross Acres	Net Acres
Alberta	5,697	844
Saskatchewan	640	24
British Columbia	66,360	16,113
Yukon Territory	3,350	1,005
Arctic Islands	3,060	153
Texas, USA	80	7
	79,187	18,146

(5) Undeveloped Acreage.

Total developed and undeveloped acreage in which the Company has interests is summarized by geographic area in the table below:

Gross and Net Petroleum Acreage as of December 31, 1996

	Developed Acres			Undeveloped Acres		
	Gross Acres	Net Acres	%	Gross Acres	Net Acres	%
Canada:						
British Columbia:						
Carried Interests	39,508	7,455	18.9	12,211	932	7.6
Working Interests	23,042	4,848	21.9	37,861	11,932	31.5
Overriding royalty interest	3,810	3,810	3.0	-	-	
Total British Columbia	66,360	16,113		50,072	12,864	
Saskatchewan:						
Working Interests	640	24	3.8	2,560	96	3.8
Alberta:						
Working Interests	5,697	844	14.8	36,285	9,929	27.4
Yukon & Northwest Territories:						
Carried Interests	3,350	1,005	30.0	31,726	9,757	30.8
Arctic Islands:						
Carried Interests	3,060	153	5.0	130,200	37,102	28.5
Working Interests	-	-		45,100	1,817	4.0
Total Arctic Islands	3,060	153		175,300	38,919	
Total Canada	79,107	18,139		295,943	71,565	
Texas, USA	80	7	8.8	-	-	
Australia	-	-		115,596	90	.1
TOTAL	79,187	18,146		411,539	71,655	

(6) Drilling activity.

Productive and dry net wells drilled during the following periods (no drilling in Australia):

	Gross		Net	
Year/Period Ended	Productive	Dry	Productive	Dry
1996	10	2	1.044	.150
1995	1	3	.033	.258
1994	8	-	1.000	-

(7) Present Activities.

There was no drilling activity at December 31, 1996.

(8) Delivery Commitments.

None.

Item 3. Legal Proceedings.

The Company, which has a 30% interest in the Kotaneelee gas field, believes that the working interest owners in the field have not adequately pursued the attainment of contracts for the sale of Kotaneelee gas. In October 1989 and in March 1990, the Company filed statements of claim in the Court of Queens Bench of Alberta, Judicial District of Calgary, Canada, against the working interest partners in the Kotaneelee gas field. The named defendants were Amoco Canada Petroleum Corporation, Ltd., Dome Petroleum Limited (now Amoco Canada Resources Ltd.), and Amoco Production Company (collectively the "Amoco Dome Group"), Columbia Gas Development of Canada Ltd. ("Columbia"), Mobil Oil Canada Ltd. ("Mobil") and Esso Resource of Canada Ltd. ("Esso") (collectively the "Defendants").

The Company claims that the Defendants breached either a contract obligation or a fiduciary duty owed to the Company to market gas from the Kotaneelee gas field when it was possible to so do. The Company asserts that marketing the Kotaneelee gas was possible in 1984 and that the Defendants deliberately failed to do so. The Company seeks money damages and the forfeiture of the Kotaneelee gas field. The Company expects to argue at trial that the money damages sustained by the Company are at least $86 million.

In addition, the Company has claimed that the Company's carried interest account should be reduced because of the negligent operation of the field and improper charges to the carried interest account by the Defendants. The Company claims that when the Defendants in 1980 suspended production from the field's gas wells, they failed to take precautionary measures necessary to protect and maintain the wells in good operating condition. The wells thereafter deteriorated, which caused unnecessary expenditures to be incurred, including expenditures to redrill one well. In addition, the Company claims that expenditures made to repair and rebuild the field's dehydration plant should not have been necessary had the facilities been properly constructed and maintained by the Defendants. The expenditures, the Company claims, were inappropriately charged to the field's carried interest account. The effect of an increased carried interest account is to extend the period before payout begins to the carried interest account owners.

The Company claims that production from the field should have commenced in 1984. At that time the field's carried interest account was approximately $63 million. The Company claims that by 1993 at least $34 million of unnecessary expenses had been wrongfully charged to the carried interest account. The Company's 30% share of these expenses would be approximately $10.2 million. The Company further claims that if production had commenced in 1984, the carried interest account would have been paid off in approximately two years and the Company would have begun to receive revenues from the field in 1986. At present, the Company does not expect to receive revenues before 1999 based on a price of $1.34 per mcf and current production rates.

Columbia has filed a counterclaim against the Company seeking, if the Company is successful in its claim for the forfeiture of the field, repayment from the Company of all sums Columbia has expended on the Kotaneelee lands before the Company is entitled to its interest.

The parties to the litigation have conducted extensive discovery since the filing of the claims. The trial began on September 3, 1996. The trial was suspended after approximately three weeks of testimony pending resolution of the Company's motion to disqualify Amoco's litigation counsel on the basis that a partner in the firm representing Amoco had served as the Company's Canadian securities counsel for many years. The Company's motion was denied and the denial was upheld on appeal. The Company has filed with the Supreme Court of Canada an application for leave to appeal that decision. The parties have agreed to expedite the application and a decision whether the Supreme Court will review the decision is expected by the end of April. If the Supreme Court refuses to hear the case, trial is expected to resume on May 5, 1997.

Matters Ancillary to Kotaneelee Litigation

In its 1989 statement of claim, the Company sought a declaratory judgment regarding two issues:

(1) whether interest accrued on the carried interest account; and

(2) whether expenditures for gathering lines and dehydration equipment are expenditures chargeable to the carried interest account or whether the Company will be assessed a processing fee on gas throughput.

With respect to the first issue, the Company maintains that no interest should accrue on the account and the Defendants have not contested this position. With regard to the second issue, the Company maintains that the expenditures are chargeable to the carried interest account. Mobil, Esso and Columbia have essentially agreed to the Company's position while the Amoco Dome Group continues to contest this issue.

On January 22, 1996, the Company settled two claims outstanding against the Company in the Court of Queens Bench, Calgary, Alberta, which related to a suit brought against AlliedSignal Inc. ("AlliedSignal") in Florida which was dismissed on the basis that Canada was the appropriate forum for the litigation. AlliedSignal had sought additional relief against the Company in Canada to preclude other types of suits by the Company and to recover the costs of the defense of the initial action. The settlement bars Allied Signal from making a claim against the Company for any costs in connection with the Kotaneelee Litigation. The Company agreed not to bring any action against AlliedSignal in connection with the Kotaneelee gas field. Neither party made any monetary payment to the other party.

In 1991, Anderson Exploration Ltd. acquired all of the shares in Columbia and changed its name to Anderson Oil & Gas Inc. ("Anderson"). Anderson is now the sole operator of the field and is a direct defendant in the Canadian lawsuit. Columbia's previous parent, The Columbia Gas System, Inc., which was reorganized in a bankruptcy proceeding in the United States, is contractually liable to Anderson in the legal proceeding described above.

The working interest owners have reported that they have been selling Kotaneelee gas since February 1991.

Under Canadian law certain costs of the litigation are assessed against the nonprevailing party. These costs consist primarily of attorney's and expert witness fees during trial. The trial is presently scheduled to last twelve months, therefore, these costs could be substantial. While the costs are not now determinable, the Company estimates that such costs, assuming a twelve month trial, could be approximately $1.5 million. However, a judge in complex and lengthy trials has the discretion to double an award of costs. There are no assurances however, that such costs will not exceed this amount or that the duration of the trial will not exceed twelve months.

There is no assurance that the Company will be successful on the merits of its claims, which have been vigorously defended by the Defendants. There is also no assurance that the Company will be awarded any damages, or that, if damages are awarded, the Court will apply the measure of damages the Company claims should be applied.

Item 4. Submission of Matters to a Vote of Security Holders

Not applicable.

Executive Officers of the Company.

The following information with respect to the executive officers of the Company is furnished pursuant to Instruction 3 to Item 401(b) of Regulation S-K.

Name	Age	Office	Length of Service in this Office	Other Positions Held with Company
Charles J. Horne	71	President	Since 1980	Director
M. A. Ashton	61	Executive Vice President	Since 1993	Director

All officers of the Company are elected annually by the Board of Directors and serve at the pleasure of the Board of Directors.

The Company is aware of no arrangement or understanding between any of the individuals named above and any other person pursuant to which any individual named above was selected as an officer.

PART II

Item 5. Market for the Company's Limited Voting Shares and Related Stockholder Matters.

(a) Principal Markets.

The Company's Limited Voting Shares, par value $1.00 per share, are traded on The Toronto Stock Exchange and the Pacific and Boston Stock Exchanges, and in the NASDAQ SmallCap market.

The quarterly high and low closing prices (in Canadian dollars) on The Toronto Stock Exchange during the calendar periods indicated were as follows:

1995	1st quarter	2nd quarter	3rd quarter	4th quarter
High	7.875	7.75	9.00	10.25
Low	6.00	6.75	6.25	8.375

1996	1st quarter	2nd quarter	3rd quarter	4th quarter
High	11.25	11.50	11.55	10.25
Low	7.75	8.00	8.50	8.50

The quarterly high and low closing prices (in United States dollars) on the Pacific Stock Exchange during the calendar periods indicated were as follows:

1995	1st quarter	2nd quarter	3rd quarter	4th quarter
High	5 5/8	6	6 3/4	7 1/2
Low	4 3/8	4 13/16	4 5/8	6 1/4

1996	1st quarter	2nd quarter	3rd quarter	4th quarter
High	8 1/8	8 1/4	8 1/2	7 5/8
Low	6	6 1/8	6 3/8	6 1/2

(b) Approximate Number of Holders of Limited Voting Shares at March 3, 1997.

Title of Class	Approximate Number of Record Holders
Limited Voting Shares, par value $1.00 per share.	6,500

(c) Dividends.

The Company has never paid a dividend on its Limited Voting Shares. Any future dividends will be dependent on the Company's earnings, financial condition, and business prospects. The Company is legally restricted from paying any dividend or making any other payment to shareholders (except by way of return of capital) on the Limited Voting Shares until its accumulated deficit ($19,385,000 at December 31, 1996) is eliminated.

Current Canadian law does not restrict the remittance of dividends to persons not resident of Canada. Under current Canadian tax law and the United States-Canada tax treaty, any dividends paid to U.S. shareholders are currently subject to a 15% Canadian withholding tax.

Item 6. Selected Financial Data.

The following selected consolidated financial information (in thousands except per share a exchange rate data) of the Company insofar as it relates to each of the fiscal periods shown has be extracted from the Company's consolidated financial statements. Effective July 1, 1993, the Compa changed its year end from June 30 to December 31.

	Year ended December 31,				Year ended June 30,
	1996 ($)	1995 ($)	1994 ($)	1993 ($)	1993 ($)
Operating revenues	1,755	1,657	1,691	1,915	2,061
Total revenues	2,228	1,793	1,942	2,103	2,389
Net loss	(1,461)	(1,162)	(1,210)	(977)	(613)
Net loss per share	(.11)	(.09)	(.10)	(.08)	(.05)
Working capital	8,403	1,510	2,417	3,890	3,750
Total assets	20,375	12,380	13,390	14,484	14,104
Shareholders' Equity:					
Capital stock	38,888	29,635	29,513	29,513	28,739
Deficit	(19,385)	(17,923)	(16,762)	(15,552)	(14,999)
	19,503	11,712	12,751	13,961	13,740
Average number of shares outstanding	13,362	12,622	12,613	12,453	12,363
Exchange rates:					
Year-end	.7297	.7329	.7129	.7554	.7801
Average for the period	.7335	.7289	.7324	.7757	.8013
Range	.7234-.7520	.7026-.7480	.7098-.7634	.7436-.8045	.7768-.8458

U.S. GAAP Information

Under U.S. generally accepted accounting principles ("GAAP"), the above selected information would as follows (See Note 6 in Notes to Consolidated Financial Statements):

Net loss	(1,236)	(1,001)	(1,140)	(673)	(613)
Net loss per share	(.09)	(.08)	(.09)	.05	(.05)

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

(1) Liquidity and Capital Resources.

At December 31, 1996, the Company had approximately $8.4 million of cash and securities available. These funds are expected to be used for general corporate purposes, including exploration and development and to continue the Kotaneelee field litigation.

Cash flow used in operations during 1996 decreased to $775,000 compared to $783,000 during the 1995 period. The $8,000 difference between the periods was caused primarily by the following:

Increase in loss from operations	$217,000
Increase in accounts receivable	220,000
Increase in accounts payable and accrued liabilities	(247,000)
Decrease in prepaid insurance and deferred costs	(198,000)
Difference in net cash used in operations	$ (8,000)

A significant proportion of the Company's property interests are covered by carried interest agreements, which provide that expenditures made by the operator are recouped solely out of revenues from production. Major capital expenditures made by the operators have an impact on the Company's cash flow from operations as no revenues are reported or received until the capital costs have been recovered by the operator. Properties in the Fort Nelson, British Columbia area in which the Company has carried interests have reached payout status. Proceeds from these carried interests plus oil and gas sales from working interest properties are the Company's major sources of working capital. During 1996, however, capital expenditures in the Fort Nelson area resulted in a temporary suspension of carried interest revenue.

The Company is currently evaluating and expects to continue to evaluate oil and gas properties and may make investments in such properties utilizing cash on hand. The Company anticipates that its capital expenditures for land acquisitions and drilling for the year 1997 will be approximately $2,300,000. The $1,110,000 increase in net cash used in investing activities during the 1996 period compared to the 1995 period reflects the Company's effort to expand its oil and gas exploration program. In addition, substantial continuing expenses are expected to be incurred in connection with the Kotaneelee Litigation. The expense of the Kotaneelee Litigation has been the principal cause of the Company's losses since 1991.

The Company has established a reserve for its potential share of future site restoration costs. The estimated amount of these costs, which total $728,000, is being provided on a unit of production basis in accordance with existing legislation and industry practice.

(2) **Results of Operations.**

1996 vs. 1995

The net loss for the year 1996 was $1,461,283, ($.11 per share) compared to a net loss of $1,161,763 ($.09 per share) for the 1995 period. A summary of revenue and expenses during the periods is as follows:

	1996	1995	Net Change
Revenues	$2,228,393	$1,793,112	$435,281
Costs and expenses	3,689,676	2,954,875	734,801
Net loss	$(1,461,283)	$(1,161,763)	$(299,520)

Oil sales increased by 38% due primarily to a 14% increase in the average price of oil sold with an 18% increase in production. There was also a 13% increase in royalties paid. Oil unit sales in barrels ("bbls") (before deducting royalties) and the average price per barrel sold during the periods indicated were as follows:

	1996			1995		
	bbls	Average price per bbl	Total	bbls	Average price per bbl	Total
Oil sales	34,565	$25.47	$880,000	29,198	$22.39	$654,000
Royalties paid			(111,000)			(98,000)
Total			$769,000			$556,000

Gas sales increased 8%. There was a 26% increase in the average price for gas which was partially offset by a 22% decrease in units sold. In addition, gas sales include royalty income which increased 17% in 1996. The volumes in million cubic feet ("mmcf") and the average price of gas per thousand cubic feet ("mcf") sold during the periods indicated were as follows:

	1996			1995		
	mmcf	Average price per mcf	Total	mmcf	Average price per mcf	Total
Gas sales	197	$1.64	$323,000	252	$1.30	$327,000
Royalty income			108,000			92,000
Royalties paid			(36,000)			(52,000)
Total			$395,000			$367,000

Proceeds under carried interest agreements decreased 20% to $591,000 during 1996 compared to $734,000 in 1995. The operator of the Company's carried interest properties increased its development activities during late 1996, thereby incurring additional expenses. Proceeds under carried interest agreements are derived from gross production revenues after payout of these expenses.

Interest and other income was 247% higher in 1996. Interest income increased from $90,000 to $258,000 in 1996 due to the increase in funds available for investment from the June 1996 rights offering to shareholders. In addition, the 1996 period includes proceeds from the sale of seismic data in the amount of $215,000 compared to $46,000 in 1995.

General and administrative costs decreased 10% in 1996 to $895,000 from $988,000 in 1995. The 1995 period included higher salary expenses related to retired personnel. In addition, accounting and administrative expenses also decreased in 1996 due to cost reduction efforts.

Lease operating costs decreased 5% from $504,000 to $477,000 in 1996. The decrease represents lower charges by the operators of the Company's properties during 1996.

Legal expenses increased 83% to $1,610,000 from $880,000 in 1995. These expenses are related primarily to the cost of the Kotaneelee litigation which increased as a result of trial preparation and the actual costs of the trial which began on September 3, 1996.

Depletion, depreciation and amortization expense increased 31% in 1996 to $655,000 from $500,000 in 1995. The increase in depletion is the result of a decrease in gas reserves and an increase in estimated capital costs.

Provision for restoration costs increased to $24,600 in 1996 compared to $16,800 in 1995. During 1996, a charge of $81,000 was made to the future site restoration costs account for certain abandonments costs. The Company has re-evaluated its potential liability and accordingly increased its provision for restoration costs.

A foreign exchange gain of $25,000 was recorded in 1996, contrasted with a loss of $14,000 on the Company's U.S. investments in 1995. In 1996, the gain was attributable to a strengthening of the U.S. dollar as compared to the Canadian dollar on the Company's U.S. investments.

Income taxes. No provision for income taxes is required for the current period.

Fiscal Year Ended December 31, 1995 vs. 1994

The net loss for the year 1995 was $1,161,763, ($.09 per share) compared to a net loss of $1,210,109 ($.10 per share) for the 1994 period. A summary of revenue and expenses during the periods is as follows:

	1995	1994	Net Change
Revenues	$1,793,112	$1,942,289	$(149,177)
Costs and expenses	2,954,875	3,152,398	197,523
Net loss	$(1,161,763)	$(1,210,109)	$ 48,346

Oil sales increased by 2% due primarily to a 17% increase in the average price of oil sold which offset a 16% decrease in production. There was also a 16% decrease in royalties paid. Oil unit sales in barrels ("bbls") (before deducting royalties) and the average price per barrel sold during the periods indicated were as follows:

	1995			1994		
	bbls	Average price per bbl	Total	bbls	Average price per bbl	Total
	29,198	$22.39	$654,000	34,711	$19.14	$664,000
Royalties paid			(98,000)			(116,000)
Total			$556,000			$548,000

Gas sales decreased 25%. There was a 29% decrease in the average price for gas which was partially offset by a 8% increase in units sold. In addition, gas sales includes royalty income which decreased 31% in 1995. The volumes in million cubic feet ("mmcf") and the average price of gas per thousand cubic feet ("mcf") sold during the periods indicated were as follows:

	1995			1994		
	mmcf	Average price per mcf	Total	mmcf	Average price per mcf	Total
Gas sales	252	$1.30	$327,000	234	$1.84	$431,000
Royalty income			92,000			134,000
Royalties paid			(52,000)			(78,000)
Total			$367,000			$487,000

Proceeds under carried interest agreements increased 12% to $734,066 during 1995 compared to $656,303 in 1994. The operator of the Company's carried interest properties significantly increased its development activities during the late 1994 and early 1995, thereby incurring additional expenses. Proceeds under carried interest agreements are derived from gross production revenues after payout of these expenses. The latter part of 1995 benefited from these development activities by increased production.

Interest and other income was 46% lower in 1995. Interest income was lower in 1995 due to the decrease in funds available to invest during 1995 compared to the prior year. In addition, 1995 includes proceeds from the sale of seismic data in the amount of $46,124 compared to $125,368 in 1994.

General and administrative costs decreased 18% in 1995. The 1994 period included the additional expenses of the Special Meeting of Shareholders held in July 1994 and associated costs. The 1994 period also included higher salary expenses related to retired personnel.

Legal expenses were 5% lower in 1995 compared to the prior year. These expenses are related primarily to the Kotaneelee litigation in which discovery is now substantially complete. These expenses are expected to increase in 1996 as a result of trial preparation and the conduct of the trial scheduled to commence on September 3, 1996.

Depletion, depreciation and amortization expense was 13% higher in 1995 due to an increase in estimated future capital costs to develop existing reserves.

A foreign exchange loss of $13,915 was recorded in 1995, contrasted with a gain of $57,791 on U.S. cash investments in 1994. During 1995, the Company had a minimal amount invested in the United States. In 1994, the significant gain was attributable to a strengthening of the U.S. dollar as compared to the Canadian dollar on the Company's U.S. investments.

Provision for restoration costs decreased to $16,800 in 1995 compared to $76,656 in 1994. The Company has re-evaluated its potential liability and accordingly reduced its provision for restoration costs.

Rent expense was 7% lower in the 1995 period as a result of lower pass-through operating costs under the lease.

Income taxes. No provision for income taxes was required for 1995.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT AUDITORS

To the Shareholders of
Canada Southern Petroleum Ltd.

We have audited the accompanying consolidated balance sheets of Canada Southern Petroleum Ltd. as at December 31, 1996 and 1995, and the consolidated statements of operations and deficit, cash flows and limited voting shares and contributed surplus for each of the years in the three year period ended December 31, 1996. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Canada Southern Petroleum Ltd. as at December 31, 1996 and 1995 and the results of its operations and the changes in its financial position for each of the years in the three year period ended December 31, 1996, in accordance with accounting principles generally accepted in Canada.

Calgary, Canada
March 6, 1997

ERNST & YOUNG
Chartered Accountants

CANADA SOUTHERN PETROLEUM LTD.

(Incorporated under the laws of Nova Scotia)

CONSOLIDATED BALANCE SHEETS

(Expressed in Canadian dollars)

	December 31, 1996	December 31, 1995
Assets		
Cash and cash equivalents (Note 2)	$2,709,597	$ 1,181,581
U.S. Government securities (Note 3)	3,404,213	-
Accounts and interest receivable	635,223	350,598
Prepaid insurance and other	227,368	226,539
Other	-	112,903
Total current assets	6,976,401	1,871,621
U.S. Government securities (Note 3)	2,048,573	-
Oil and gas properties and equipment (full cost method) (Note 4)	11,349,945	10,508,619
	$20,374,919	$12,380,240
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable	$ 439,837	$ 125,509
Accrued liabilities (Note 10)	182,104	236,332
Total current liabilities	621,941	361,841
Future site restoration costs	250,274	306,728
Contingencies (Notes 8 and 11)	-	-
Shareholders' Equity		
Limited Voting Shares, par value $1 per share (Note 5)		
Authorized - 100,000,000 shares		
Outstanding -13,956,540 (1995 - 12,645,791) shares	13,956,540	12,645,791
Contributed surplus	24,930,964	16,989,397
	38,887,504	29,635,188
Deficit	(19,384,800)	(17,923,517)
Total shareholders' equity	19,502,704	11,711,671
	$20,374,919	$12,380,240

See accompanying notes.

CANADA SOUTHERN PETROLEUM LTD.

Consolidated Statements of Operations and Deficit
(Expressed in Canadian dollars)

	Year ended December 31,		
	1996	1995	1994
Revenues:			
Oil sales	$ 768,576	$ 555,894	$ 547,509
Gas sales	395,068	366,700	486,764
Proceeds under carried interest agreements	590,935	734,066	656,303
Interest and other income	473,814	136,452	251,713
	2,228,393	1,793,112	1,942,289
Costs and expenses:			
General and administrative	894,766	988,395	1,204,565
Legal (Note 9)	1,610,477	879,821	928,560
Lease operating costs	476,562	503,648	502,452
Depletion, depreciation, and amortization	654,982	499,630	441,033
Foreign exchange (gains)	(24,693)	13,915	(57,791)
Provision for future site restoration costs	24,600	16,800	76,656
Rent	52,982	52,666	56,923
	3,689,676	2,954,875	3,152,398
Loss before income taxes	(1,461,283)	(1,161,763)	(1,210,109)
Income taxes (Note 6)	-	-	-
Net loss	(1,461,283)	(1,161,763)	(1,210,109)
Deficit - beginning of period	(17,923,517)	(16,761,754)	(15,551,645)
Deficit - end of period	$(19,384,800)	$(17,923,517)	$(16,761,754)
Average number of shares outstanding	13,362,410	12,621,560	12,612,791
Net loss per share	$(.11)	$(.09)	$(.10)

See accompanying notes.

CANADA SOUTHERN PETROLEUM LTD.
Consolidated Statements of Cash Flows
(Expressed in Canadian dollars)

	Year ended December 31,		
	1996	1995	1994
Cash flows from operating activities:			
Net loss	$(1,461,283)	$(1,161,763)	$(1,210,109)
Adjustments to reconcile net loss to net cash provided by (used in) operating activity:			
Depreciation, depletion and amortization	654,982	499,630	441,033
Future site restoration costs (net)	(56,454)	16,800	76,656
Change in assets and liabilities:			
Accounts and interest receivable	(284,625)	(64,491)	143,390
Prepaid insurance and other	112,074	(85,775)	(40,034)
Accounts payable	314,328	(38,583)	(27,797)
Accrued liabilities	(54,228)	51,620	67,723
Net cash used in operations	(775,206)	(782,562)	(549,138)
Cash flows from investing activities:			
Additions to oil and gas properties (net)	(1,496,308)	(383,519)	(1,090,969)
U.S. Government securities purchased	(5,452,786)	-	-
Repayments of loans due Company	-	-	310,000
Net cash used in investing activities	(6,949,094	(383,519)	(780,969)
Cash flows from Financing Activities:			
Sale of common stock less expenses	9,019,609	-	-
Exercise of stock options	232,707	121,780	-
Net cash from financing activities	9,252,316	121,780	-
Increase (decrease) in cash and cash equivalents	1,528,016	(1,044,301)	(1,330,107)
Cash and cash equivalents at the beginning of period	1,181,581	2,225,882	3,555,989
Cash and cash equivalents at the end of period (Note 2)	$2,709,597	$1,181,581	$2,225,882

See accompanying notes.

CANADA SOUTHERN PETROLEUM LTD.

CONSOLIDATED STATEMENTS OF LIMITED VOTING SHARES AND CONTRIBUTED SURPLUS
(Expressed in Canadian dollars)

	Number of shares	Limited Voting Shares $1 par value	Contributed surplus	Total
Balance at December 31, 1993 and 1994	12,612,791	12,612,791	16,900,617	29,513,408
Exercise of stock options	33,000	33,000	88,780	121,780
Balance at December 31, 1995	12,645,791	$12,645,791	$16,989,397	$29,635,188
Sale of common stock	1,268,549	1,268,549	7,751,060	9,019,609
Exercise of stock options	42,200	42,200	190,507	232,707
Balance at December 31, 1996	$13,956,540	$13,956,540	$24,930,964	$38,887,504

See accompanying notes.

1. Summary of significant accounting policies

Accounting principles

The Company prepares its accounts in accordance with accounting principles generally accepted in Canada which, except as described in Note 6, conform in all material respects with United States generally accepted accounting principles ("U.S. GAAP").

Consolidation

The consolidated financial statements include the accounts of Canada Southern Petroleum Ltd. and its wholly-owned subsidiaries, Canpet Inc. and C.S. Petroleum Limited.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Cash and cash equivalents

For the purposes of the statement of cash flows, the Company considers all highly liquid investments with a maturity of three months or less to be cash equivalents.

Oil and gas properties and equipment

The Company, which is engaged primarily in one industry, the exploration for and the development of oil and gas properties, principally in Canada, follows the full cost method of accounting for oil and gas properties, whereby all costs associated with the exploration for and the development of oil and gas reserves are capitalized.

The Company periodically reviews the costs associated with undeveloped properties and mineral rights to determine whether they are likely to be recovered. When such costs are not likely to be recovered, such costs are transferred to the depletable pool of oil and gas costs.

1. Summary of significant accounting policies (Cont'd)

The net carrying cost of the Company's oil and gas properties in producing cost centers is limited to an estimated recoverable amount. This amount is the aggregate of future net revenues from proved reserves and the costs of undeveloped properties, net of impairment allowances, less future general and administrative costs, financing costs and income taxes. Future net revenues are calculated using year end prices that are not escalated or discounted.

The costs of the Company's 30% carried interest in the Kotaneelee gas field are included in oil and gas properties and in the cost center for the purpose of computing depletion. In addition, the Company's share of estimated net reserves after payout are also included in the proved oil and gas reserves base for the purpose of computing depletion. However, no revenue production data will be reported for financial statement purposes until the Company is entitled to participate in the field's revenue after payout status is achieved.

Gains or losses are not recognized upon disposition of oil and gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20% or more.

Depletion is provided on costs accumulated in producing cost centers including well equipment using the unit of production method. For purposes of the depletion calculation, gross proved oil and gas reserves as determined by outside consultants are converted to a common unit of measure on the basis of their approximate relative energy content.

Depreciation has been computed for equipment, other than well equipment, on the straight-line method based on estimated useful lives of four to ten years.

Substantially all of the Company's exploration and development activities related to oil and gas are conducted jointly with others and accordingly the consolidated financial statements reflect only the Company's proportionate interest in such activities.

Revenue recognition

The Company recognizes revenue on its working interest properties from the production of oil and gas in the period the oil and gas are sold.

Revenue under carried interest agreements is recorded in the period when the proceeds become receivable. The Company is entitled to participate in oil and gas net revenues after the repayment of exploration, drilling and completion expenses to the party or parties bearing these costs. The carried interest accounts are subject to independent audits which are performed in subsequent years. In the past, these audits have resulted in both positive and negative adjustments. For these reasons, the proceeds under carried interest agreements may fluctuate each year depending on both capital expenditures and any audit adjustments.

1. Summary of significant accounting policies (Cont'd)

Earnings per share

Earnings per limited voting share is based upon the weighted average of shares outstanding during the period. Primary and fully diluted earnings per share are the same.

Future site restoration costs

Estimated future site restoration costs which are estimated to be $728,000 are being provided on a unit of production basis. The provision is based on current costs of complying with existing legislation and industry practice for site restoration and abandonment. At December 31, 1996, approximately $478,000 in such costs have not been accrued.

Deferred income taxes

The Company follows the deferral method of tax allocation accounting whereby the income tax provision is based on pre-tax income reported in the accounts. Under this method, full provision is made for deferred income taxes resulting from claiming deductions at the rates permitted by income tax legislation, which may differ from those used in the accounts.

Foreign currency translation

Transactions for settlement in U.S. dollars have been translated at average monthly exchange rates. Assets and liabilities in U.S. dollars have been translated at the year end exchange rates. Exchange gains or losses resulting from these adjustments are included in costs and expenses.

2. Cash and cash equivalents

The Company considers all highly liquid short term investments with maturities of three months or less at date of acquisition to be cash equivalents. Cash equivalents are carried at cost which approximates market value.

	1996	1995
Cash	$ 319,616	$ 326,031
Canadian bankers acceptances (2.65%)	1,441,170	855,550
U.S. Treasury Bills (4.75%)	948,811	-
	$2,709,597	$1,181,581

(Expressed in Canadian dollars)

3. U.S. Government Securities

At December 31,1996, the Company has the following amounts invested in U.S. government securities which are expected to be held until maturity:

Security	Par value	Maturity Date	Amortized Cost	Fair value
U.S. Treasury Bill	$ 822,256	Mar. 27, 1997	$ 801,637	$ 812,570
U.S. Treasury Bill	685,213	Apr. 3, 1997	657,599	676,271
U.S. Treasury Bill	2,055,639	Jun. 26, 1997	1,944,977	2,004,289
Total short term	3,563,108		3,404,213	3,493,130
U.S. Treasury Bill	2,055,639	Jun. 26, 1998	2,048,573	2,056,914
Total	$5,618,747		$5,452,786	$5,550,044

4. Oil and gas properties and equipment

	Cost	Accumulated Provisions and Writedowns	Net Book Value
Balance December 31, 1996			
Oil and gas properties-developed	$18,555,130	$7,227,874	$11,327,256
Oil and gas properties-undeveloped	1	-	1
Seismic data	112,000	112,000	-
	18,667,131	7,339,874	11,327,257
Equipment	62,172	39,484	22,688
	$18,729,303	$7,379,358	$11,349,945
Balance December 31, 1995			
Oil and gas properties - developed	$17,069,321	$6,590,176	$10,479,145
Oil and gas properties - undeveloped	1	-	1
Seismic data	112,000	104,508	7,492
	17,181,322	6,694,684	10,486,638
Equipment	57,865	35,884	21,981
	$17,239,187	$6,730,568	$10,508,619

Substantially all gas sales were made to CanWest Gas Supply Inc. and oil sales were made to Canadian Natural Resources Ltd.

5. Limited voting shares and stock options

The Memorandum of Association (Articles of Continuance) of the Company provides that no person (as defined) shall vote more than 1,000 shares.

(Expressed in Canadian dollars)

5. Limited voting shares and stock options (Cont'd)

Under the terms of the Company's 1985 and 1992 stock option plans, the Company is authorized to grant certain key employees and consultants options to purchase limited voting shares at prices based on the market price of the shares as determined on the date of the grant. The options are exercisable for five years from the date of grant.

On June 24, 1996, the Company concluded its offering of approximately 1.3 million shares to its shareholders at $7.50 per share. The offering was oversubscribed and the proceeds to the Company were $9,019,609 after deducting the $494,509 cost of the offering.

Following is a summary of option transactions which reflects adjustments of the stock option prices and the number of shares subject to stock options as discussed above:

Options outstanding	Number of shares	Option Prices ($)
December 31, 1993	159,700	3.45 - 4.06
Granted	335,000	7.00
December 31, 1994	494,700	3.45 - 7.00
Exercised	(33,000)	3.45 - 4.06
December 31, 1995	461,700	
Canceled	(137,000)	3.45 - 7.00
Exercised	(42,200)	3.45 - 8.75
Granted	150,700	3.15 - 6.37
Granted	12,500	8.75
December 31, 1996	445,700	
Options reserved for future grants	212,134	

On July 8, 1996, 137,000 options to purchase limited voting shares of the Company which were previously granted were canceled and reissued to reflect the June 1996 rights offering.

For U.S. GAAP, the Company has elected to follow Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB No. 25) and related interpretations in accounting for its stock options because the alternative fair value accounting provided under FASB Statement No. 123, "Accounting for Stock Based Compensation," requires use of option valuation models that were not developed for use in valuing stock options. Under APB No. 25, because the exercise price of the Company's stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recognized.

(Expressed in Canadian dollars)

5. Limited voting shares and stock options (Cont'd)

Pro forma information regarding net income and earnings per share is required by Statement 123, and has been determined as if the Company had accounted for its stock options under the fair value method of that Statement. The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model.

Option valuation models require that input of highly subjective assumptions including the expected stock price volatility. The assumptions used in the valuation model were: risk free interest rate - 6.7%, expected life - 5 years and expected volatility - .396.

Because the Company's stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion, the existing models do not necessarily provide a reliable single measure of the fair value of its stock options.

For the purpose of pro forma disclosures, the estimated fair value of the stock options is expensed in the year of grant since the options are immediately exercisable. The Company's pro forma information follows:

	Amount	Per Share
Net loss as reported - December 31, 1996	$(1,461,283)	$(.11)
Stock option expense	49,373	-
Pro forma net loss	$(1,510,656)	$(.11)

6. Income taxes

Income taxes vary from the amounts that would be computed by applying the Canadian federal and provincial income tax rates as follows:

	Year ended December 31,		
	1996	1995	1994
	44.84%	44.84%	44.84%
Provision for income taxes based on combined basic Canadian federal and provincial income tax	$(577,532)	$(520,935)	$(542,614)
Nondeductible crown charges	61,599	60,354	72,577
Other	478	948	1,707
Unrealized tax loss	515,455	459,633	468,330
Actual provision for income taxes	$ -	$ -	$ -

At December 31, 1996, the Company had net operating losses for income tax purposes of approximately $3,217,000 which are available to be carried forward to future periods. These losses expire in the following years: 1998 - $563,000, 1999 - $194,000, 2000 - $294,000, 2001 - $545,000, 2002 - $569,000 and 2003 - $1,052,000.

(Expressed in Canadian dollars)

6. Income taxes (Cont'd)

At December 31, 1996, the following oil and gas tax deductions are available to reduce future taxable income, subject to a final determination by taxation authorities.

Drilling, exploration and lease acquisition costs	$11,103,000
Earned depletion	1,975,000
Undepreciated capital costs	1,463,000
Cumulative eligible capital losses	407,000
Share issue costs	495,000

The tax benefits attributable to the above accumulated expenditures will not be reflected in the consolidated financial statements until such benefits are realized.

Under U.S. GAAP, the provisions for income taxes would have differed for the reasons set out below:

In February 1992, the United States Financial Accounting Standards Board issued Statement No. 109, "Accounting for Income Taxes", effective for fiscal years beginning after December 15, 1993. Under U.S. GAAP, the Company would have been required to adopt Statement No. 109 commencing July 1, 1993.

Under Statement No. 109, the liability method is used in accounting for income taxes. Under this method, deferred tax assets and liabilities are determined based on differences between financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Under Canadian GAAP and previously under U.S. GAAP, income tax expense is determined using the deferral method. Deferred tax expense is based on items of income and expense that are reported in different years in the financial statements and tax returns and are measured at the tax rate in effect in the year the differences originated.

The following schedule summarized the Company's income tax expense and deferred tax liability under U.S. GAAP. If Statement No. 109 was adopted, the Company would have had a deferred tax asset which primarily represents the excess of available resource deductions for income tax purposes over the recorded value of oil and gas properties together with operating and capital income tax loss carryforwards. These amounts are expected to be recovered from the production of current oil and gas reserves when the Kotaneelee litigation expenditures have ended. As certain of the resource deductions are restricted and the operating loss carryforwards are subject to expiration, there is considerable risk that certain of these deductions will not be utilized. Accordingly, the Company would have established a valuation allowance to recognize this uncertainty. Income taxes computed in accordance with U.S. GAAP, would have resulted in a credit to the provision of taxes.

(Expressed in Canadian dollars)

6. Income taxes (Cont'd)

	December 31,		
	1996	1995	1994
Deferred tax asset	$3,233,506	$2,351,550	$2,169,085
Valuation reserve	(2,473,526)	(1,816,792)	(1,795,307)
Net deferred tax asset	$ 759,980	$ 534,758	$ 373,778
Deferred tax recovery	$ 225,222	$ 160,980	$ 69,995

Net loss under U.S. GAAP, in total, and per share based on average number of shares outstanding during the periods shown is as follows:

	Year ended December 31,		
	1996	1995	1994
Net loss under Canadian GAAP before income taxes	$(1,461,283)	$(1,161,763)	$(1,210,109)
Income tax adjustment	8 225,222	160,980	69,995
Net loss under U.S. GAAP	$(1,236,061)	(1,000,783)	$(1,140,114)
Per Share Basis:			
Net loss under Canadian GAAP before income taxes	$(.11)	$(.09)	$(.10)
Income tax adjustment	.02	.01	.01
Net loss under U.S. GAAP	$(.09)	$(.08)	$(.09)

The deficit under U.S. GAAP would have been $18,624,820 and $17,388,759 at December 31, 1996 and 1995, respectively. 8 759,980

7. Line of credit

The Company has a line of credit with a Canadian chartered bank which provides for a loan of $500,000. The line of credit provides for a $125,000 operating loan and $375,000 for letters of credit as part of the directors' indemnification agreements. The interest rate on borrowing is at 3/4% above the bank's prime lending rate. The line of credit is subject to annual review and is secured by a general assignment of accounts receivable and an undertaking to provide security in the form of assignment of future working interest proceeds. No drawings were made under this line during 1996 or 1995.

8. Litigation

The Company, which has a 30% interest in the Kotaneelee gas field, believes that the working interest owners in the field have not adequately pursued the attainment of contracts for the sale of Kotaneelee gas. In October 1989 and in March 1990, the Company filed statements of claim in the Court of Queens Bench of Alberta, Judicial District of Calgary, Canada, against the working interest partners in the Kotaneelee gas field. The named defendants were Amoco Canada Petroleum Corporation, Ltd., Dome Petroleum Limited (now Amoco Canada Resources Ltd.), and Amoco Production

Company (collectively the "Amoco Dome Group"), Columbia Gas Development of Canada Ltd. ("Columbia"), Mobil Oil Canada Ltd. ("Mobil") and Esso Resource of Canada Ltd. ("Esso") (collectively the "Defendants").

The Company claims that the Defendants breached either a contract obligation or a fiduciary duty owed to the Company to market gas from the Kotaneelee gas field when it was possible to so do. The Company asserts that marketing the Kotaneelee gas was possible in 1984 and that the Defendants deliberately failed to do so. The Company seeks money damages and the forfeiture of the Kotaneelee gas field. The Company expects to argue at trial that the money damages sustained by the Company are at least $86 million.

In addition, the Company has claimed that the Company's carried interest account should be reduced because of the negligent operation of the field and improper charges to the carried interest account by the Defendants. The Company claims that when the Defendants in 1980 suspended production from the field's gas wells, they failed to take precautionary measures necessary to protect and maintain the wells in good operating condition. The wells thereafter deteriorated, which caused unnecessary expenditures to be incurred, including expenditures to redrill one well. In addition, the Company claims that expenditures made to repair and rebuild the field's dehydration plant should not have been necessary had the facilities been properly constructed and maintained by the Defendants. The expenditures, the Company claims, were inappropriately charged to the field's carried interest account. The effect of an increased carried interest account is to extend the period before payout begins to the carried interest account owners.

The Company claims that production from the field should have commenced in 1984. At that time the field's carried interest account was approximately $63 million. The Company claims that by 1993 at least $34 million of unnecessary expenses had been wrongfully charged to the carried interest account. The Company's 30% share of these expenses would be approximately $10.2 million. The Company further claims that if production had commenced in 1984, the carried interest account would have been paid off in approximately two years and the Company would have begun to receive revenues from the field in 1986. At present, the Company does not expect to receive revenues before 1999 based on a price of $1.34 per mcf (average 1996 price) and current production rates.

Columbia has filed a counterclaim against the Company seeking, if the Company is successful in its claim for the forfeiture of the field, repayment from the Company of all sums Columbia has expended on the Kotaneelee lands before the Company is entitled to its interest.

8. Litigation (Cont'd)

The parties to the litigation have conducted extensive discovery since the filing of the claims. The trial began on September 3, 1996. The trial was suspended after approximately three weeks of testimony pending resolution of the Company's motion to disqualify Amoco's litigation counsel on the basis that a partner in the firm representing Amoco had served as the Company's Canadian securities counsel for many years. The Company's motion was denied and the denial was upheld on appeal. The Company has filed with the Supreme Court of Canada an application for leave to appeal that decision. The parties have agreed to expedite the application and a decision whether the Supreme Court will review the decision is expected by the end of April. If the Supreme Court refuses to hear the case, trial is expected to resume on May 5, 1997.

Matters Ancillary to Kotaneelee Litigation

In its 1989 statement of claim, the Company sought a declaratory judgment regarding two issues:

(1) whether interest accrued on the carried interest account; and

(2) whether expenditures for gathering lines and dehydration equipment are expenditures chargeable to the carried interest account or whether the Company will be assessed a processing fee on gas throughput.

With respect to the first issue, the Company maintains that no interest should accrue on the account and the Defendants have not contested this position. With regard to the second issue, the Company maintains that the expenditures are chargeable to the carried interest account. Mobil, Esso and Columbia have essentially agreed to the Company's position while the Amoco Dome Group continues to contest this issue.

On January 22, 1996, the Company settled two claims outstanding against the Company in the Court of Queens Bench, Calgary, Alberta, which related to a suit brought against AlliedSignal Inc. ("AlliedSignal") in Florida which was dismissed on the basis that Canada was the appropriate forum for the litigation. AlliedSignal had sought additional relief against the Company in Canada to preclude other types of suits by the Company and to recover the costs of the defense of the initial action. The settlement bars Allied Signal from making a claim against the Company for any costs in connection with the Kotaneelee Litigation. The Company agreed not to bring any action against AlliedSignal in connection with the Kotaneelee gas field. Neither party made any monetary payment to the other party.

In 1991, Anderson Exploration Ltd. acquired all of the shares in Columbia and changed its name to Anderson Oil & Gas Inc. ("Anderson"). Anderson is now the sole operator of the field and is a direct defendant in the Canada Court lawsuits. Columbia's previous parent, The Columbia Gas System, Inc., which was reorganized in a bankruptcy proceeding in the United States, is contractually liable to Anderson in the legal proceeding described above.

8. Litigation (Cont'd)

The working interest owners have reported that they have been selling Kotaneelee gas since February 1991.

Under Canadian law certain costs of the litigation are assessed against the nonprevailing party. These costs consist primarily of attorney's and expert witness fees during trial. The trial is presently scheduled to last twelve months, therefore, these costs could be substantial. While the costs are not now determinable, the Company estimates that such costs, assuming a twelve month trial, could be approximately $1.5 million. However, a judge in complex and lengthy trials has the discretion to double an award of costs. There are no assurances however, that such costs will not exceed this amount or that the duration of the trial will not exceed twelve months.

There is no assurance that the Company will be successful on the merits of its claims, which have been vigorously defended by the Defendants. There is also no assurance that the Company will be awarded any damages, or that, if damages are awarded, the Court will apply the measure of damages the Company claims should be applied.

9. Related party transactions

Fees paid or accrued for legal services rendered to the Company by Reasoner, Davis & Fox, (of which firm Mr. C. Dean Reasoner, a director of the Company, is a partner,) were U.S. $111,000, $133,000 and $111,000 for the years 1996, 1995 and 1994, respectively. Mr. Reasoner resigned as a director on March 11, 1997.

In 1991, the Company granted interests to certain of its officers, employees, directors, counsel and consultants amounting to an aggregate of 7.8% of any and all benefits to the Company after expenses from the litigation in Canada relating to the Kotaneelee gas field. The Company has reserved a 2.2% interest in such net benefits for possible future grants to persons who may include officers and directors of the Company.

Directors Heath and Reasoner have royalty interests in certain of the Company's oil and gas properties, (present and past) which were received directly or indirectly through the Company. During the years 1996,1995 and 1994, the Company and third-party operators and/or owners of properties made payments pursuant to these royalties for the benefit of Mr. Reasoner and Mr. Heath in the amounts of U.S. $5,342, $6,159 and $13,263 and U.S. $10,844, $12,777 and $28,604, respectively.

(Expressed in Canadian dollars)

10. Other financial information

Accrued liabilities

	1996	1995
Accrued liabilities due to working interest partners	$ 12,050	$ 23,830
Accrued accounting and legal expenses	52,793	107,228
Accrued royalties	116,415	99,405
Other	846	5,869
	$182,104	$ 236,332

	Year ended December 31,		
	1996	1995	1994
Royalty payments (1)	$146,673	$150,224	$191,785
Interest payments (2)	$ 7,099	$ 10,000	$ 10,746
Large corporation tax payments	$ 2,741	$ 4,527	$ 7,740

(1) *Oil and gas sales are reported net of royalties paid.*
(2) *Bank line of credit charges.*

11. Contingency

The operator of one of the Company's carried interest properties, which includes approximately 36 wells, is claiming that certain payments made in 1995 and 1996 were outside the area of mutual interest. The Company is disputing the claim of $319,000 at December 31, 1996 and a resolution of the claim is not expected until an independent audit of the carried interest account is completed. If it is subsequently determined that the operator's claim is valid, then any overpayment will be recovered from the future revenues of these properties.

CANADA SOUTHERN PETROLEUM LTD.
SUPPLEMENTAL INFORMATION ON OIL AND GAS ACTIVITIES
(unaudited)

The following information includes estimates which are subject to rapid and unanticipated change. Therefore, these estimates may not accurately reflect future net income to the Company.

The Company has no proved oil and gas reserves in Australia that require disclosure under SEC regulations and no revenues from oil and gas production in that country. All amounts below except for costs, acreage, wells drilled and present activities relate to Canada. Oil and gas reserve data and the information relating to cash flows were provided by Paddock Lindstrom & Associates Ltd., independent consultants.

Estimated net quantities of proved oil and gas reserves:

	Oil (bbls)	Gas (bcf)
Proved reserves:		
December 31, 1993	441,000	33.831
Revisions of previous estimates	66,488	0.207
Production*	(33,888)	(1.081)
December 31, 1994	473,600	32.957
Revisions of previous estimates	(157,908)	1.559
Production*	(30,892)	(1.311)
December 31,1995	284,800	33.205
Revisions of previous estimates	178,448	(2.655)
Production	(37,448)	(1.519)
December 1996	425,800	29.031
Proved developed reserves:		
December 31, 1994	473,600	32.957
December 31, 1995	284,800	33.205
December 31, 1996	358,400	28.265

* Production data includes oil and gas sales and the proceeds from the carried interest properties.

Results of oil and gas operations:

	Year ended December 31, 1996	1995	1994
Income:			
Oil and gas sales	1,163,644	$ 922,594	$1,034,273
Proceeds under carried interest agreements	590,935	734,066	656,303
	1,754,579	1,656,660	1,690,576
Costs and expenses:			
Production costs	476,562	503,648	502,452
Depletion depreciation, and amortization	654,982	499,630	441,033
Provision for future site restoration costs	24,600	16,800	76,656
Income tax expense	-	-	-
	1,156,144	1,020,078	1,020,141
Net income from operations	$ 598,453	$ 636,582	$ 670,435

Costs of oil and gas activities:

	Year ended Year ended December 31, 1996	1995	1994
Acquisition costs	$484,000	$ 49,000	$395,000
Exploration	146,000	92,000	253,000
Development	866,000	243,000	443,000

Standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities during the following period (in thousands of dollars):

	Year ended December 31, 1996	1995	1994
Future cash inflows	$ 49,410	$ 48,298	$56,981
Future development and production costs	(20,813)	(18,473)	(20,796)
	28,597	29,825	36,185
Future income tax expense*	(2,931)	(4,218)	(6,778)
Future net cash flows	25,666	25,607	29,407
10% annual discount	(9,691)	(10,679)	(12,890)
Standardized measure of discounted future net cash flows	$ 15,975	$ 14,928	$16,517

* Reflects tax benefit for the year ended December 31, 1996 and 1995, from carryforward of exploration, development and lease acquisition costs, undepreciated capital costs and book earned depletion of $17,032,000, $13,679,000 and $13,520,000.

Current prices used in the foregoing estimates were based upon selling prices at the wellhead in the last month of each fiscal period. Current costs were based upon estimates made by consulting engineers at the end of each year.

Changes in the standardized measure during the following periods (in thousands of dollars):

	Year ended December 31, 1996	1995	1994
Changes due to:			
Prices and production costs	$3,248	$(88)	$ (21)
Future development costs	(1,049)	83	4
Sales net of production costs	(1,330)	(1,428)	(1,188)
Development costs incurred during the year	866	243	443
Net change due to extensions, discoveries and improved recovery	1,458	-	358
Revisions of quantity estimates	(4,229)	(3,404)	(214)
Accretion of discount	1,660	1,927	1,832
Net change in income taxes	423	1,078	740
Other	-	-	141
Net change	$1,047	$(1,589)	$2,095

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

PART III

For information concerning Item 10 - Directors and Executive Officers of the Company, Item 11 - Executive Compensation, Item 12 - Security Ownership of Certain Beneficial Owners and Management and Item 13 - Certain Relationships and Related Transactions, see the Proxy Statement of Canada Southern Petroleum Ltd. relative to the Annual Meeting of Shareholders for the fiscal year ended December 31, 1996, which will be filed with the Securities and Exchange Commission, which information is incorporated herein by reference. For information concerning Item 10 - Executive Officers of the Company, see Part I.

Mr. C. Dean Reasoner resigned as a Director of the Company for health-related reasons on March 11, 1997. On March 13, 1997, Mr. Arthur B. O'Donnell, a former vice president of the Company, was elected to complete Mr. Reasoner's term as a director. Mr. O'Donnell, a CPA, has over 40 years experience in the oil and gas business.

PART IV

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K.

(a) (1) Financial Statements.

The financial statements listed below and included under Item 8, above are filed as part of this report.

(2) Consolidated Financial Statement Schedules.

All schedules have been omitted since the required information is not present or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or the notes thereto.

(3) Exhibits.

The following exhibits are filed as part of this report:

Item Number.

2. Plan of acquisition, arrangement, liquidation or succession

None

3. Articles of Incorporation and By-Laws.

Memorandum of Association as amended on June 30, 1982, May 14, 1985 and April 7, 1988 and Bye-laws, as amended, filed as Exhibit 3 to Registration Statement No. 33-99052 as filed on November 7, 1995.

4. Instruments defining the rights of security holders, including indentures.

None.

9. Voting trust agreement.

None.

10. Material contracts.

(a) Agreements relating to Kotaneelee.

(1.) Copy of Agreement dated May 28, 1959 between the Company et al. and Home Oil Company Limited et al. and Signal Oil and Gas Company filed as Exhibit 10(a)(1) to Registration Statement No. 33-99052 as filed on November 7, 1995 is incorporated herein by reference.

(2.) Copies of Supplementary Documents to May 28, 1959 Agreement (see (1) above), dated June 24, 1959, consisting of Guarantee by Home Oil Company Limited and Pipeline Promotion Agreement, filed as Exhibit 10(a)(2) to Registration Statement No. 33-99052 as filed on November 7, 1995 is incorporated herein by reference.

(3.) Copy of Modification to Agreement dated May 28, 1959 (see (1) above), made as of January 31, 1961, filed as Exhibit 10(a)(3) to Registration Statement No. 33-99052 as filed on November 7, 1995 is incorporated herein by reference.

(4.) Copy of Agreement dated April 1, 1966 among the Company et al. and Dome Petroleum Limited et al. filed as Exhibit 10(a)(4) to Registration Statement No. 33-99052 as filed on November 7, 1995 is incorporated herein by reference.

(5.) Copy of Letter Agreement dated February 1, 1977 between the Company and Columbia Gas Development of Canada, Ltd. for operation of the Kotaneelee gas field filed as Exhibit 10(a) to Registration Statement No. 33-99052 as filed on November 7, 1995 is incorporated herein by reference.

(b) Copy of Agreement dated January 28, 1972 between the Company and Panarctic Oils Ltd. for development of the offshore Arctic Islands gas fields filed as Exhibit 10(b) to Registration Statement No. 33-99052 as filed on November 7, 1995 is incorporated herein by reference.

(c) Stock Option Plan adopted December 9, 1992 filed as Exhibit 10(g) to Report on Form 10-K for the fiscal year ended June 30, 1993 is incorporated herein by reference.

11. Statement re computation of per share earnings.

Not applicable.

12. Statement re computation of ratios.

None.

13. Annual report to security holders.

Not applicable.

16. Letter re change in certifying accountant.

Not applicable.

18. Letter re change in accounting principles.

None.

20. Previously unfiled documents.

None.

21. Subsidiaries of the Company.

Canpet Inc. incorporated in Delaware on August 3, 1973.
C. S. Petroleum Limited incorporated in Nova Scotia on December 15, 1981.

22. Published report regarding matters submitted to vote of security holders.

None.

23. Consents of experts and counsel.

(a) Paddock Lindstrom & Associates, Ltd.
(b) Ernst & Young

24. Power of attorney.

Not applicable.

27. Financial Data Schedule.

Filed herein.

28. Information from reports furnished to state insurance regulatory authorities.

Not applicable.

99. Additional exhibits.

(a) Complaint of Allied-Signal Inc. in its action against Dome Petroleum Limited, Amoco Production Company, and Amoco Canada Petroleum Company Ltd. filed September 2, 1988 in the Court of Queens Bench of Alberta, Judicial District of Calgary, Canada, filed as Exhibit 99(a) to Registration Statement No. 33-99052 as filed on November 7, 1995 is incorporated herein by reference.

(b) Answer and Counterclaim of Dome Petroleum Limited, Amoco Production Company, and Amoco Canada Petroleum Company Ltd. filed September 21, 1988 in the Court of Queen's Bench of Alberta, Judicial District of Calgary, Canada, which answers the Allied-Signal complaint in (b) above and which names the Company and others as counterclaim defendants, filed as Exhibit 99(b) to Registration Statement No. 33-99052 as filed on November 7, 1995 is incorporated herein by reference.

(c) Statement of Claim filed on October 27, 1989 against Columbia Gas Development of Canada Ltd., Amoco Production Company, Dome Petroleum Limited, Amoco Canada Petroleum Company Ltd., Mobil Oil Canada Ltd. and Esso Resources of Canada Ltd. in the Court of Queen's Bench of Alberta Judicial District of Calgary, Alberta, Canada filed as Exhibit 99(c) to Registration Statement No. 33-99052 as filed on November 7, 1995 is incorporated herein by reference.

(d) Amended Statement of Claim, amending the October 27, 1989 Statement of Claim, filed on March 12, 1990 and filed as Exhibit 99(d) to Registration Statement No. 33-99052 as filed on November 7, 1995 is incorporated herein by reference.

(e) Amended Statement of Claim in the same action, filed on November 17, 1993, filed as Exhibit 28(ii) to Form 8-K dated November 17, 1993 is incorporated herein by reference.

(f) Amended Statement of Third Party Notice by Amoco Canada Production Company Ltd. and Amoco Production Company, filed November 17, 1993 in the same action, and filed as Exhibit 99(e).

(g) Amended Statement of Defense to Third Party Notice by Anderson Oil & Gas Inc. (formerly Columbia Gas Development of Canada Ltd.) filed January 27, 1994 in the same action, and filed as Exhibit 99(g) to Form 10-K dated for the period ended December 31, 1993, is incorporated herein by reference.

(h) Documents regarding settlement with AlliedSignal Inc. as Exhibits to Form 8-K as filed on January 30, 1996 are incorporated herein by reference.

(1) Covenant Not to Sue.

(2) Discontinuance of Action. Action No. 8801-13549 Court of Queen's Bench of Alberta Judicial District of Calgary.

(3) Order. Action No. 8801-123549 Court of Queens Bench of Alberta Judicial District of Calgary.

(4) Partial Discontinuance of Counterclaim. Action No. 8801-13549 Court of Queens Bench of Alberta Judicial District of Calgary.

CANADA SOUTHERN PETROLEUM LTD.

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Denver, Colorado

Arthur B. O'Donnell
Consultant
West Hartford, Connecticut

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CSP WEB SITE
Beginning May 1, 1997, financial results, corporate news and other company information will be available on the Company's web site: http://www.cansopet.com

All shareholder correspondence relating to stock ownership or address changes, lost stock certificates, and other such matters should be directed to the Company's Transfer Agents in Canada or in the United States, as shown above. Other inquiries may be directed to Canada Southern's Executive Offices in Calgary, or, if more convenient, to the Company, c/o G&O'D INC, 149 Durham Road, Oak Park-Unit 31, Madison, Connecticut 06443. Telephone: (203) 245-7664

The ticker symbol used on the Toronto, Boston and Pacific Exchanges is **CSW.**

The NASDAQ SmallCap Market uses the ticker symbol **CSPLF**.

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